U.S. House of Representatives
Energy & Commerce Committee
Subcommittee on Oversight and Investigations

September 7, 2006

Steve Marshall
President, BP Exploration (Alaska) Inc.

Written Testimony

My name is Steve Marshall and I am President of BP Exploration (Alaska) Inc. (BPXA). BPXA is the operator of the largest oil field in North America – Prudhoe Bay on Alaska's North Slope.

I will discuss BPXA's Prudhoe Bay oil field operations and the actions taken on August 6th to begin the orderly shutdown of Prudhoe Bay - a decision I believe was our only option in order to avoid the risk of an oil spill. I will also present some background material on the corrosion prevention programs in the field.

Prudhoe Bay

The Prudhoe Bay field is located 650 miles north of Anchorage and 400 miles north of Fairbanks. It is 1200 miles from the North Pole and 250 miles north of the Arctic Circle. Pump Station 1, the beginning of the Trans Alaska Pipeline System (TAPS), is located within the perimeter of the Prudhoe Bay field. For additional detail on Prudhoe Bay operations please refer to Exhibit 1 in the appendix.

Prior to 2000 the Prudhoe Bay field comprised the East Operating Area, operated by Atlantic Richfield Company (ARCO), and the West Operating Area, operated by BPXA. Upon acquisition of ARCO by BP, BPXA became the sole operator of Greater Prudhoe Bay. Although BPXA operates the field, a total of nine companies have a so-called "working interest" in the field leases. The costs and production are shared amongst the working interest owners, according to their ownership.

In March of 2006, BPXA discovered a leak along the GC-21 line in the Western Operating Area (Exhibit 2). This is a 34" line that carries sales quality crude oil to a central gathering center for ultimate delivery into TAPS at pump station 1. The leak was approximately 5,000 barrels, the largest spill ever on the Alaskan North Slope. Shortly thereafter, the U.S. Department of Transportation (DOT) issued a Corrective Action Order (CAO) to BPXA ordering it to perform "smart pig" tests along with other inspection methods along both the Western and Eastern Oil Transit Lines (OTLs). There were a number of complex technical issues to resolve before the tests could be conducted, including developing a solution for managing the solids generated during the pigging operation.

BPXA began pigging operations along the Lisburne OTL in June. In-Line Inspection (ILI) of the Lisburne OTL showed good results and affirmed our confidence that the lines where fit for service. BPXA began pigging operations along the Eastern OTL in early July. Analyses of these "smart pig" inspections were received on Friday, August 4 and indicated 16 significant anomalies at 12 different locations along a segment of the Eastern OTL. BPXA began immediate physical and ultrasonic testing of these anomalies and verified the presence of additional corrosion. BPXA's inspections also revealed insulation staining along a segment of the Eastern OTL. With the knowledge of these results, BPXA immediately shut down production at Flow Station 2 as a precautionary measure and BPXA technicians subsequently discovered a small leak after close visual inspection along the FS-2 to FS-1 pipeline segment.

The smart pig results along the Eastern OTL were unexpected. Because the exact cause of the corrosion mechanism was unknown, BPXA was concerned over the condition of the Western OTL. Thus, BPXA took the prudent step on the morning of August 6 of announcing our intent to systematically shut-down both sides of the Prudhoe Bay field until existing inspection data could be further assessed and verified with follow up inspections.

Some have questioned whether BPXA made a rash decision to shut down the field over a small leak. To me, as President of BPXA, the decision to shut-down was a reaffirmation of BP's values and was the responsible thing to do. We took this step to prevent a potential release from occurring.

In light of these incidents, many have alleged that BPXA's inspection and maintenance program was inadequate. Given our almost 30 year performance history and our existing programs, we believed we had an effective corrosion management program in place. Clearly, recent events have shown that our program did not detect the type of pitting corrosion identified here. We are examining and analyzing this data closely to ensure that we apply this learning to improve our program.

BP Corrosion Prevention Program for the North Slope

Corrosion is the natural degradation of a material like steel pipe that results from a reaction with its environment. While corrosion cannot be eliminated, it can be effectively managed through a combination of monitoring and mitigation treatments. The goal of corrosion mitigation programs is to control corrosion rates to acceptable levels.

Corrosion rates are not static, however, and they can increase or decrease depending on fluid properties or changes in conditions that affect the efficacy of corrosion inhibitors. For that reason, locations that are prone to corrosion damage, or where damage has been identified, are inspected as often as every three to six months.

BPXA uses pigging, ultrasonic testing (UT), visual inspections, corrosion inhibitors and other techniques as appropriate for each individual oil field's characteristics. We employ a risk-based management program whereby resources/activities are concentrated in areas where corrosion is expected to occur. Exhibits 3 and 4 describe the operations of a gathering center in producing, separating and pumping oil and show a graphical representation of a producing field.

BPXA's program was designed to control corrosion, extending the useful life of valuable North Slope infrastructure. The 2006 annual budget for BPXA's corrosion monitoring and mitigation program is $74 million, an increase of 15 percent from 2005, and 80% from 2001. As Exhibit 5 demonstrates, corrosion management "spend" has increased significantly over the last 5 years despite the reduction in Prudhoe Bay production volumes.

Inhibition

A key element of the program is widespread continuous inhibitor injection. In short, the best way to address corrosion is to prevent it from happening in the first place. Our commitment to effectively managing corrosion on the North Slope is reflected in our corrosion inhibitor injection rates. Exhibit 6 is a diagram of the inhibitor concentrations and the corresponding corrosion rates achieved as measured by corrosion coupons.

We continuously monitor the effectiveness of the inhibition programs with corrosion coupons and electrical resistance (ER) probes. The ER probes take readings every 4 hours of the corrosion potential of the fluids and allow us to make adjustments to corrosion inhibitor injection rates on a weekly basis. Exhibit 7 is a typical configuration of a corrosion coupon and ER probe.

We have not been satisfied with simply maintaining the *status quo*. We conduct an on-going and very active inhibitor research program outlined in Exhibit 8.

Monitoring and Inspections

BP's North Slope pipeline monitoring and inspection program incorporates combinations of ultrasonic, radiographic, magnetic flux, guided wave and electromagnetic inspection techniques. Ultrasonic and radiographic testing are used as an indicator to trigger further action and is sound for pipelines that are accessible above-ground.

BPXA's overall annual inspection program consists of conducting inspections at about 100,000 locations on pipelines in Prudhoe Bay. Of these inspections, approximately 60,000 are for internal corrosion inspection and approximately 40,000 are for external corrosion inspection.

BPXA runs approximately 370 maintenance pigs per year on the North Slope. In addition, we utilize coupon monitoring, smart pigging, leak detection systems and surveillance by personnel to provide integrity assurance and maintain safe operations (See Exhibit 9 for detail regarding pigging operations).

Lines are pigged in Prudhoe Bay either because of mechanical issues or because corrosion monitoring suggests it. The frequency of pigging is specific to each pipeline and varies significantly across the North Slope and the industry. For example, the Northstar oil pipeline is pigged every two weeks to prevent paraffin buildup.

Another technology is ultrasonic testing (UT) which involves the use of a high frequency sound wave to produce a precise measurement of the thickness of a material. Our UT inspections are not simply one reading at one location on the pipe. Rather, they are an inspection of the full circumference of the pipe over a one foot length. So when we count one UT inspection, it is really hundreds of individual readings at one location. The technology is a proven diagnostic tool routinely used for corrosion monitoring.

We also use corrosion coupons (see Exhibit 7) throughout our operations in order to obtain additional information about any corrosive conditions that might exist in our systems that escaped other inhibition and monitoring programs. The majority of our coupons are read on a three to four month basis.

Important components of pipeline inspections also include regular visual inspections and the use of Forward Looking Infrared (FLIR) devices. FLIR technology is used to spot heat signatures of crude oil and is especially useful during winter months.

Mitigation of Corrosion

In the design of pipelines, many corrosion mitigation methods are considered. The selection of material from which to manufacture pipe, such as corrosion resistant alloys like stainless or low carbon steel, is one consideration. Another option is the use of various coatings and linings that provide pipelines protection against corrosive agents.

Technology used to protect metal structures from corrosion includes cathodic protection, a technique that is usually used in buried pipelines and takes advantage of electrochemical properties that reduces a metal structure's corrosion potential.

Mitigation also involves the application of corrosion inhibitors and biocides in conjunction with preventative maintenance such as pigging and physical repair of external damage.

External corrosion is mitigated by removal of the source for the water, drying, cleaning and buffing of the damage area and application of new insulation and/or coatings. If external corrosion limits the integrity of the pipeline, then repair techniques are used such as sleeves, clock springs, clamps and or composite wraps.

If the programs are so good, what happened?

The recent leaks were on the oil transit lines, which are the last step in the process before TAPS. By this point, the major corrosion battles have already been fought. General corrosion and pitting in the OTLs were monitored by corrosion coupons on a quarterly basis, and have consistently shown very low corrosive conditions in these lines, always below the BP targeted wall thickness loss of less than .002 inches per year. Exhibit 10 shows coupon results in the OTLs. In spite of their low corrosivity, the OTLs were included in our on-going UT monitoring program. Monitoring results were confirmed annually, and have consistently revealed corrosion to be under control on these lines.

It has been frequently reported that BPXA didn't perform in-line inspections (ILI) on these lines, and that if we had, this problem would have been prevented. In fact, the March 2006 pipeline failure occurred on the WOA line, which had been pigged in both 1990 and 1998. These inspections did detect some corrosion (in the range of 20 to 50% in some locations). The most severe known damage locations were inspected in following years, and did not exhibit further growth. Neither the in-line inspections nor the follow-up inspections identified the corrosion problem that led to the March spill.

The first indication of a growth in corrosion came from our corrosion monitoring program in the facilities upstream of the WOA OTLs. An increase in facility corrosion upstream of the WOA OTLs, while not alarming, caused us to perform additional UT inspections of the OTLs. The results of these inspections led us to schedule another ILI of the WOA OTL for mid- 2006. Unfortunately, the March release occurred before that pig run was conducted.

It has been misreported that the OTLs have wide-spread corrosion. In fact, no evidence of general corrosion (i.e. wall loss throughout the pipe) along the OTLs has been found. If there was, it would have been quickly detected by our monitoring programs. Instead, the OTLs have widely spaced, mostly isolated dime-sized pits about 5 to 10 feet apart. The corrosion is more serious on the upstream segments of these lines, which have the lowest flow velocities.

Why wasn't the pitting corrosion detected by BP's monitoring program? BP had an active inspection program for these lines, but the isolated pits were too widely spaced to be detected by that program. For example, there was an inspection site adjacent to the site where a leak occurred. The inspection did not detect any corrosion – just a few feet away from a pit.

We initially believed that the corrosion along the WOA had developed due to certain operational changes in the WOA, and that the EOA was not similarly affected. Our initial inspections of the EOA line appeared to confirm this. However, these conclusions were premature and made before the latest inspections were completed. The inspection of the EOA OTL revealed that the pattern of corrosion damage is similar in both the EOA and WOA, although the precise corrosion mechanism remains under study.

Coffman Report

In the last few days, mention has been made of the annual reports that have been submitted by an engineering firm, Coffman, which reviewed BPXA's inspection and maintenance program on behalf of the State of Alaska and found several deficiencies in BPXA's program. The implication is that if these deficiencies had been addressed, then the recent pipeline incidents would have been prevented.

Previous Coffman reports have noted there were isolated pockets of accelerated corrosion in BPXA's North Slope infrastructure. Notably, Coffman also stated those problem areas were discovered during the regular course of inspection. Excerpts from recent Coffman reports are shown below:

- The 2003 report states: “From a global perspective of oil and gas production, Greater Prudhoe Bay (GPB) and related facilities have an aggressively managed corrosion control program. This suggests an adequate long-term commitment to preserving facilities for future production and sensitivity to environmental consequences.”
- The 2004 report credits BP with transparency and candor, and for maintaining a corrosion program in which there is no “acceptable” risk. It said BP’s program “is effective and exceeds common industry practice,” and that “Corrosion in most of the pipeline system has been reduced to a negligible level.”

When discussing internal corrosion on oil lines, the Coffman reports focus attention on the “production system” of well lines and flow lines, the “three-phase” lines that carry a mix of oil, water and gas. These are the lines where corrosion is more of a known threat than in the transit lines that carry “processed oil”. Coffman does not specifically discuss the oil transit lines in any of its reports.

Thus, while there were areas in Coffman’s reports recommending additional inspection and maintenance activities, on balance they offered support for the efficacy of BPXA’s corrosion management program.

Path Forward

BPXA's incident analysis is underway, but we have already taken steps to characterize the problem and assess the integrity of all the OTL lines. This information has been submitted to the Office of Pipeline Safety (OPS), whose staff is currently reviewing it. We also have outside experts who are reviewing the data and who will provide independent opinions about its adequacy.

We have been working in cooperation with OPS to ensure the safety and integrity of these systems. We pledge to continue working in cooperation with DOT and other interested stakeholders to ensure that these lines, and all our pipeline operations on the North Slope, are operated to a high standard of operational excellence.

Now we must focus our attention on the future – and what we will do to mitigate the risk of future leaks occurring in these oil transit lines. We have committed to undertake seven key actions:

> First - Run an in- line inspection tool in each of the Prudhoe Bay Oil Transit Lines that are returned to service.

> Second - Confirm through testing the exact corrosion mechanism that caused this problem and modify our mitigation programs accordingly.

Third - Implement maintenance pigging in all Oil Transit Lines.

Fourth - Include all BP operated Oil Transit Lines on the North Slope into DOT's Pipeline Integrity Management Program. This will cover all 122 miles of BP Oil Transit Lines in Alaska.

Fifth - Replace 16 miles of WOA / EOA oil transit lines; regardless of in line inspections outcome, in order to ensure velocity rates are acceptable. The estimated cost of this is in excess of $150 million.

Sixth - The organizational structure has been changed with the addition of a Technical Director to provide independent assurance of our integrity management efforts.

Seventh - Spending on Prudhoe Bay major maintenance will increase to $195 million in 2007, a nearly four fold increase from 2004 spending levels.

In addition to these physical changes we remain committed to work collaboratively and proactively with the DOT and State regulators.

Business Resumption Plan

Western Operating Area

BPXA has conducted more than 4,876 UT tests of the Western Operating Area OTLs subsequent to the August 6th announcement. These subsequent inspection results have not indicated any wall thickness loss greater than 36%. In addition, BPXA has begun a surveillance effort that includes daily over-flights using infrared cameras, as well as the use of hand-held infrared cameras on the ground. The cameras can detect small leaks by sensing changes in pipeline surface temperatures. Two vehicles with spill response equipment and carrying observers with infra-red leak detection equipment are patrolling the line 24 hours a day. They will be teamed with pipeline walkers who will visually inspect the line 10 times a day.

Ongoing UT inspections have slowed in recent days due to the detection of asbestos fibers in the mastic used to secure the pipeline insulation. Additional tests are being conducted to determine what (if any) additional protective measures need to be put in place to enable employees to continue to perform insulation removal.

Production had been reduced by 90,000 barrels/day due to a compressor malfunction in GC-2. Replacement of the compressor was completed on Sunday, August 27 and production in the WOA has been restored to approximately 220,000 barrels/day.

Eastern Operating Area

Work continues on removal of insulation from pipe; line inspections and testing are underway. We are averaging 200 to 300 inspections per day. About 160 workers are dedicated to this inspection effort.

We are currently inspecting the 34” segment that runs from FS-1 to Skid 50 (see Exhibit 2). If the inspection results show that the line has integrity, we will request permission to re-start that line from the DOT. We are currently working through a process with DOT to make that request once we can provide assurance that the line can be safely re-started and pigged.

This will allow resumption of partial production from Flow stations 1 and 3. After re-start, these line segments will need to be inspected with a smart pig to meet requirements imposed by the DOT. If inspection results indicate that the remaining EOA OTLs are not fit for service, then by-pass options will be completed as soon as practicable.

Regarding the leak along the FS-2 transit line, the estimated 23 barrels of oil spilled has been cleaned up. The line currently holds about 13,000 barrels of crude. Metal sleeves have been installed on those sections of the transit line with severe corrosion. BPXA has submitted a plan to the U.S. Department of Transportation for de-oiling this segment of line.

Concurrent with our inspection activities, by-pass options are being pursued to restore as much production as possible in an environmentally safe manner. The focus is largely on the EOA and includes new options to divert production from each of the existing Flow Stations to Skid 50 (see Exhibit 2).

- The production from FS-2 is being engineered to route to the Endicott production line through new piping.
- The production from FS-1 is being engineered to route to the Endicott production line through new piping.
- The production from FS-3 is being engineered to route through Drill Site 15 and then to a jumper into the Lisburne OTL.

Work on these options will be completed by the end of October.

All of this work is taking place as BPXA prepares for ultimate replacement of the 16 miles of WOA/EOA oil transit lines. Sixteen miles of pipe has been ordered and is expected on the slope during the fourth quarter. We are hopeful that work can be completed during the winter construction season.

At this point, we do not have a schedule for restoring all or a portion of EOA production and can't speculate on how long it's going to take.

While many of the circumstances surrounding the incidents at Prudhoe Bay are known there is much more that needs to be done to fully understand the corrosion mechanism we experienced. These results will be known in due course and will be shared in a fully transparent way. In the meantime, BPXA is committed to restoring full production to the EOA as soon as we are confident it can be done in a safe and environmentally responsible way.

New Pipeline Safety Regulations

Historically, certain pipelines that operate at low stress were exempt from U.S. DOT oversight. This exemption applied to onshore pipelines such as oil transit lines on the Alaskan North Slope.

However, since the March 2, 2006 spill from BP's Western OTL (a low-stress system); DOT has proposed a rule to revise the low-stress exemption. Upon completion of its rulemaking process, it is likely that any low-stress pipeline that is in an environmental high consequence area will become a regulated pipeline under DOT jurisdiction. These proposed regulatory changes are strongly supported by BP.

Employee Concerns

I'd like to now turn to a final point about a related subject that of employee concerns. A number of people have raised questions and concerns about our corrosion inspection, monitoring and prevention program. Sometimes these concerns have been voiced inside the company. Sometimes, they have been taken to regulators or to the media.

I view every employee concern as an opportunity to address a problem. I don't care how or with whom they are raised. I just want to know about them. We need the input of our workers to continuously improve and be the best business we can be.

BP feels the same way. Harassment, intimidation, retaliation and discrimination against workers who raise concerns are not tolerated within BP.

We have a number of channels through which workers can raise concerns. In addition to just the normal line management channels, we have employee-run safety committees, we have a worldwide anonymous program called Open Talk, and in Alaska we have other, confidential methods for employees to communicate workplace concerns. As you have just heard, BP America has made the decision to add an ombudsman reporting to Bob Malone with specific emphasis on Alaska issues. We also track employee satisfaction and concerns via a People Assurance Survey conducted annually. The results from the 2006 survey indicate a 13% improvement year over year for our Slope-based workforce.

BP has a track record of acting on employee concerns. Over the last several years employee safety committees have raised, and we have jointly addressed over 600 safety concerns. They range from the quality of vehicle headlights to challenging whether the injection of fluids into disposal wells was appropriate.

More importantly, BP has investigated and addressed concerns raised about our corrosion inspection, monitoring and inspection program.

During the summer of 2002 a BP employee received two anonymous calls alleging falsification of corrosion inspection reports by a handful of contract workers. BP brought in an outside firm, audited the work performed on the program year-to-date, and determined that a small percentage of inspections had indeed been falsified. The investigation also called into question our inspection contractor's quality assurance program.

Our inspection contractor dismissed the workers responsible for falsifying inspection reports and three months later, when the inspection contract was up for renewal, we brought in a new company to do this work.

As another example, in 2004, after receiving allegations of harassment, intimidation and retaliation by a BP corrosion program manager we brought in an outside law firm, Vinson and Elkins (V&E) to conduct an investigation. Vinson and Elkins found evidence of intimidating behavior that had made some corrosion workers reluctant to raise health and safety concerns.

We acted on the recommendation of V&E and transferred the manager in question outside Alaska into a technical consulting role.

When the company received non-specific allegations that cost cutting and deficiencies in the corrosion program were going to lead to a major incident on the North Slope, the BP Group sent John Baxter, BP Group chief engineer and several technical experts from outside Alaska to assess the overall quality of the program. Their review assessed the process, procedures and controls in sufficient detail to validate the results of the program with specific focus on areas thought to be encompassed by the allegations.

The top line finding of the "Baxter" audit was "BPXA has an adequate corrosion management system which to some extent may be overly detailed, but the extent, complexity and ageing state of the pipe work will always create the potential for leaks."

Again, this audit is an example of BP receiving concerns and investigating them. It resulted in recommendations for improving the program that have been or which are still being implemented.

When concerns were raised about whether BPXA had inappropriately influenced edits made in an Alaska state review of the company's corrosion management program, BP again brought in an outside law firm to investigate. The investigation found no evidence of improper behavior on the part of the company or its employees.

Bob Malone has announced today that he plans to review how the company has handled every employee concern raised in Alaska since the ARCO acquisition was completed in 2000.

I welcome the inquiry. I see it as a way to improve an important aspect of how we operate our business.

Conclusion

In closing Mr. Chairman, since March, we identified an unexpected gap in our corrosion control program, and we will correct it. In the future, we will have a better system to protect our pipelines and we have already gained important new operating knowledge.

I deeply regret the problems caused by the situation we discovered. But we will emerge stronger and more knowledgeable as a result of this challenge.

EXHIBIT 1

Fact Sheet Prudhoe Bay

Background

The Prudhoe Bay field is the largest field in North America and the 18th largest field ever discovered worldwide. Of the 25 billion barrels of original oil in place, more than 13 billion barrels can be recovered with current technology.

Prudhoe Bay field was discovered on March 12, 1968, by ARCO and Exxon with the drilling of the Prudhoe Bay State #1 well. A confirmation well was drilled by BP Exploration in 1969. The next 8 years saw frenetic activity as ARCO, BP, Exxon, and other companies with lease holdings in the vicinity worked to delineate the reservoir, resolve equity participation, and put together an initial infrastructure. Prudhoe Bay came on stream in June 20, 1977, rapidly increasing production until the field's maximum rate was reached in 1979 at 1.5 million barrels per day. This rate was maintained until early 1989, and is currently declining by 10% per year. Production totaled approximately 475,000 barrels per day on January 1, 2004. More than 10 billion barrels have already been produced.

Prior to 2000 the Prudhoe Bay field was comprised of the East Operating Area, operated by ARCO, and the West Operating Area, operated by BP Exploration. Upon acquisition of ARCO by BP and sale of ARCO Alaska assets to Phillips Petroleum, the two operating areas were consolidated and BP became the sole operator of Greater Prudhoe Bay. Although BP operates the field, a total of nine companies have an interest in the field leases. The profits and costs are shared amongst the owners, according to their ownership.

Ownership

BP Exploration (Operator), 26%
ConocoPhillips Alaska Inc., 36%
ExxonMobil, 36%
Others, 2%

Greater Prudhoe Bay Fast Facts	Discovered	1968	
	Production started	1977	
	Oil production wells	1114	
	Participating field area (including satellites)	213,543 acres	
	Daily production (thousands)	475,000 bbls/day	
	Total cumulative production (1/1/05)	BP Net	Gross
		4395	10,839
Midnight Sun Fast Facts	Production started	1998	
	Oil production wells	2	
	Participating field area (including satellites)	3,112 acres	
	Daily production (thousands)	5,500 bbls/day	
Aurora Fast Facts	Production started	2000	
	Oil production wells	10	
	Participating field area (including satellites)	7,519 acres	
	Daily production (thousands)	9,000 bbls/day	
Orion Fast Facts	Production started	2002	
	Oil production wells	3	
	Participating field area (including satellites)	18,853 acres	
	Daily production (thousands)	11,000 bbls/day	
Polaris Fast Facts	Production started	1999	
	Oil production wells	10	
	Participating field area (including satellites)	11,681acres	
	Daily production (thousands)	4,000 bbls/day	
Borealis Fast Facts	Production started	2001	
	Oil production wells	27	
	Participating field area (including satellites)	7,757 acres	
	Daily production (thousands)	19,000 bbls/day	

Location

The Prudhoe Bay field is located 650 miles north of Anchorage and 400 miles north of Fairbanks. It is 1200 miles from the North Pole and 250 miles north of the Arctic Circle. Pump Station 1, the beginning of the Trans Alaska Pipeline, is located with in the perimeter of the Prudhoe Bay field.

Source:
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EXHIBIT 1 (page 2)

Geologic Features
The Prudhoe Bay field, like many oil fields, consists of layers of porous rock that contain gas, oil, and water. The water, being the heaviest, lies in the lower rock layers of the field. The oil lies above the water, and the gas rests atop the oil. The oil, gas, and water are held in the Prudhoe Bay field by changes in the rock type (stratigraphy) and by the tilt and faulting of the rock layers. Sandstones are porous and allow the fields' fluids to flow through them. Shales, however, act as barriers to fluid flow. Thus, whenever a sandstone layer meets a shale layer, either through faulting or as a factor of how the rock was originally deposited, the shale stops the fluid flow and the fluids are trapped.

The oil at Prudhoe Bay is trapped in the Sadlerochit formation, a sandstone and gravel structure nearly 9,000 feet underground. In some locations the oil-bearing sandstone was 600 feet thick during the field's early life. Today, average thickness of the oil bearing zone is about 60 feet.

Natural gas
The field contains an estimated 46 trillion cubic feet of natural gas (in place) in an overlying gas cap and in solution with the oil. Of that, about 26 trillion cubic feet are classified as recoverable.

Investment
The major owners have invested more than $25 billion to develop the Prudhoe Bay field and the transportation system necessary to move Prudhoe Bay crude oil to market.

Satellite Fields
Since 1998 five satellite fields have been discovered and developed within the unit boundaries of the Prudhoe Bay oil field. These fields are Midnight Sun, Aurora, Orion, Polaris, and Borealis. One of the key objectives of the field's development has been to maximize sharing of existing infrastructure, including production and support facilities. The production wells for these satellite fields are located on one of the Prudhoe production pads. The liquids are processed through Prudhoe Bay facilities.

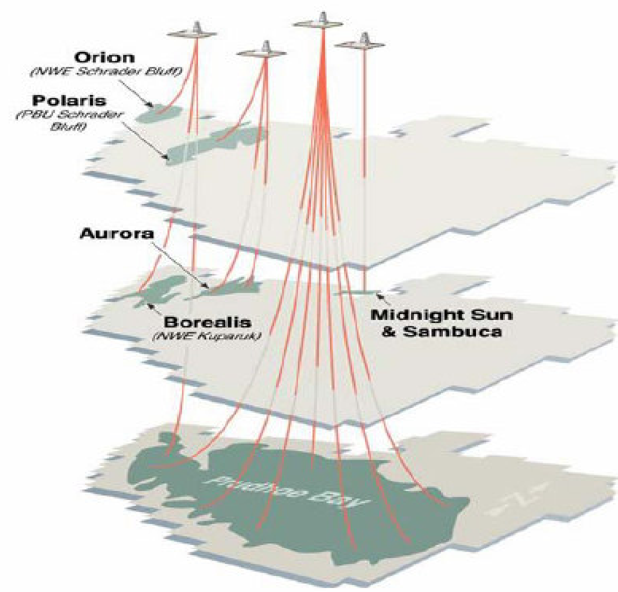

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EXHIBIT 1 (page 3)

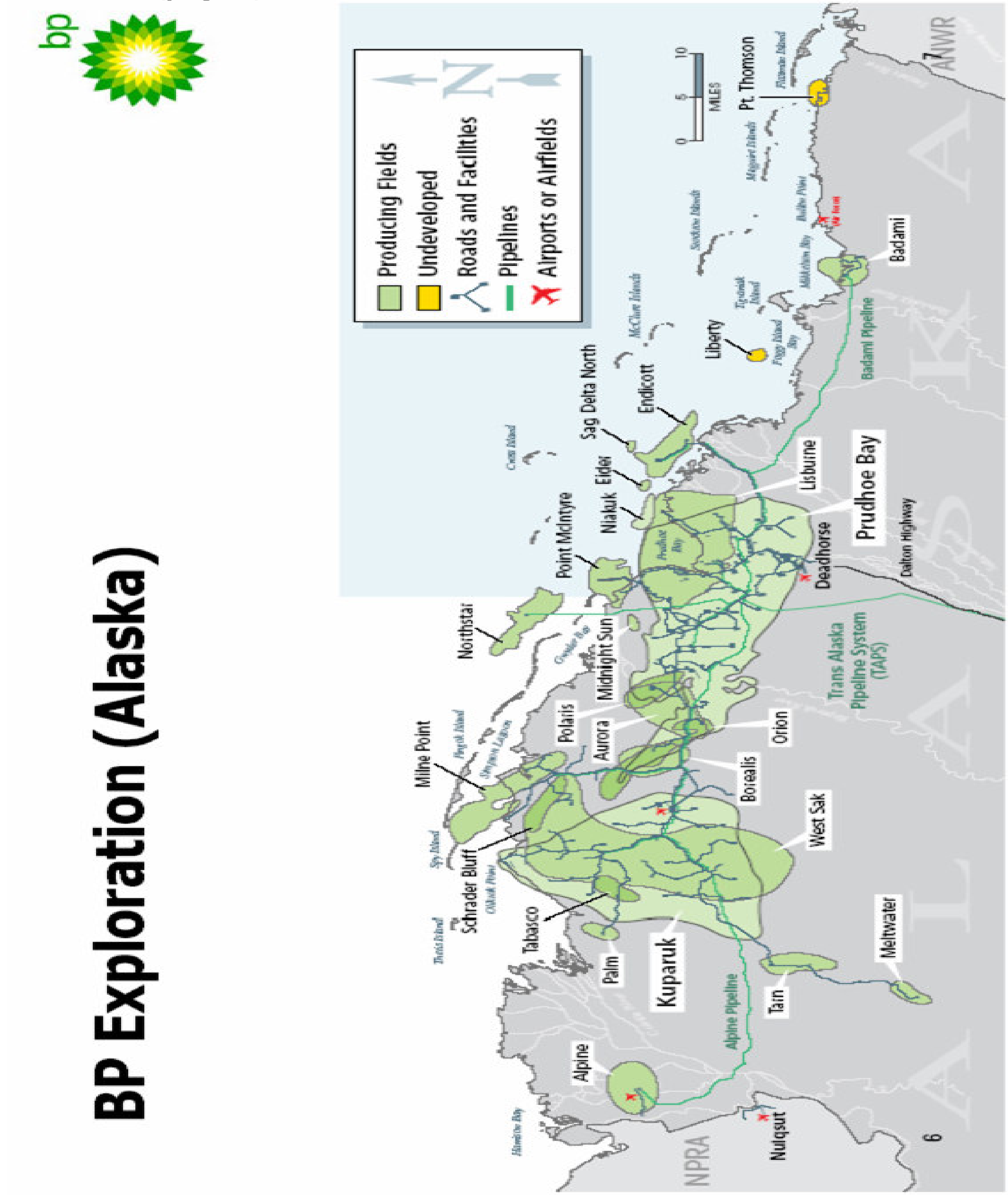


EXHIBIT 2

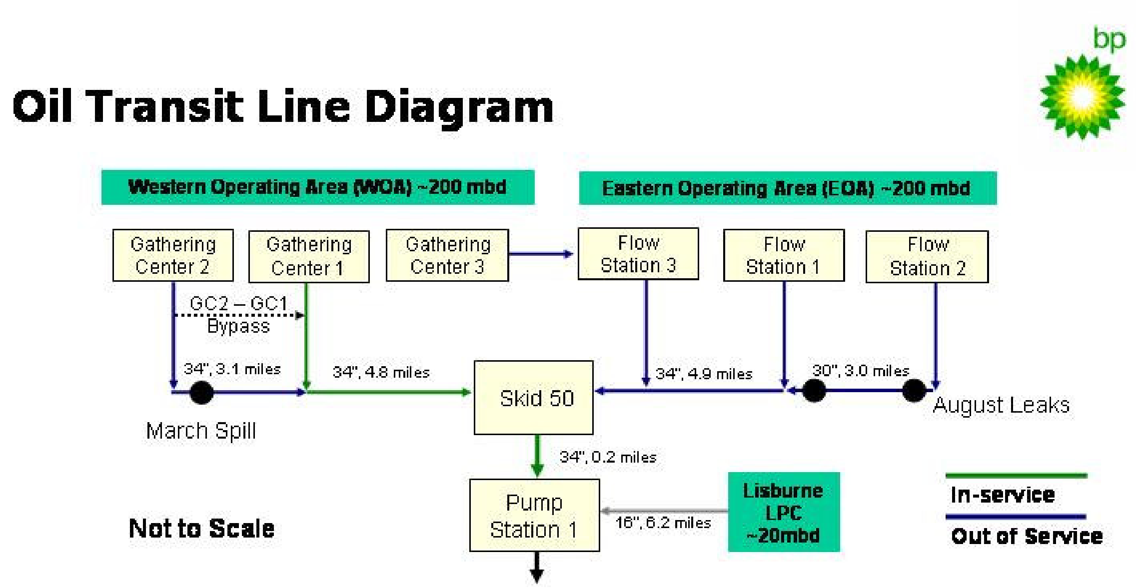

Oil Transit Line Diagram
bp
Western Operating Area (WOA) ~200 mbd
Eastern Operating Area (EOA) ~200 mbd
Gathering Center 2
Gathering Center 1
Gathering Center 3
Flow Station 3
Flow Station 1
Flow Station 2
GC2 – GC1 Bypass
34", 3.1 miles
34", 4.8 miles
Skid 50
34", 4.9 miles
30", 3.0 miles
August Leaks
March Spill
34", 0.2 miles
Pump Station 1
16", 6.2 miles
Lisburne LPC ~20mbd
In-service
Out of Service
Not to Scale

EXHIBIT 3

Fact Sheet Gathering Centers, Flow Stations

Introduction

The purpose of separation facilities (known as "**gathering centers**" on the western side of the field **GC-1, GC-2, GC-3**,and "**flow stations**" on the eastern side **Flow-1, Flow-2, Flow-3**) is to separate raw crude oil, water and gas produced from the wells into the three main components. The crude must meet certain pipeline specifications before being shipped to Pump Station 1 at the start of the Trans Alaska Pipeline System (TAPS). Each separation facility is designed to process about 350,000 barrels of raw crude oil per day. The separation facilities can also handle various amounts of gas and water. The largest gas handling facilities are Flow Station 1 and Gathering Center 1, each capable of processing 2.7 billion cubic feet of gas per day. The largest water handling facility is Flow Station 2 which can process up to 600,000 barrels of water per day.

Oil System

Raw crude produced from individual production wells located at well pads is diverted to flowlines (pipelines). The flowlines transport the raw crude to the separation facilities, where the water and natural gas mixed with the raw crude are removed. The stabilized crude is then sent to Pump Station 1, the beginning of TAPS.

Gas System

The separated natural gas is compressed, dehydrated, and transported to the Central Gas Facility (CGF) where natural gas liquids are recovered and sent to TAPS and a portion are used to make miscible injectant which is used in enhanced oil recovery. The remaining dry gas goes to the Central Compression Plant (CCP), where the majority is injected into the Sadlerochit formation. A small portion of the compressed and dehydrated produced gas is used within the Prudhoe Bay Unit as fuel gas. At GC-1 and FS-3, another portion is diverted to the "gas lift" compression plant. Gas lift is a process where recovered natural gas is re-injected into the wells to add buoyancy to the oil to help "lift" it to the surface.

Separation Facilities Fast Facts	**Separation** facilities (also called Gathering centers/ flow stations) separate natural gas and water from crude oil extracted from production wells. **There** are 6 separation facilities (3 gathering centers/ 3 flow stations) at Prudhoe Bay. Other North Slope oil fields have their own separation facilities. **Each** separation facility at Prudhoe Bay is designed to process about 350,000 barrels (14.7 million gallons) of raw crude in a day. **Each** gathering center processes an average of 70,000 barrels of oil, 1400 million cubic feet of natural gas, and 200,000 barrels of produced water each day; quantities vary from facility to facility.

Water System

The "produced" water separated from the raw crude is processed to remove oil and solids. This treatment process yields an oil stream (which is returned to oil processing equipment), a dirty water stream (which is injected into the Cretaceous formation nearly 1 mile below the Earth's surface), and a treated produced water stream (which goes to injection wells at the well pads). The treated produced water injected into the formation supports a field-wide waterflood program designed to maintain reservoir pressure and "sweep" crude oil from injection wells toward oil production wells.

EXHIBIT 4

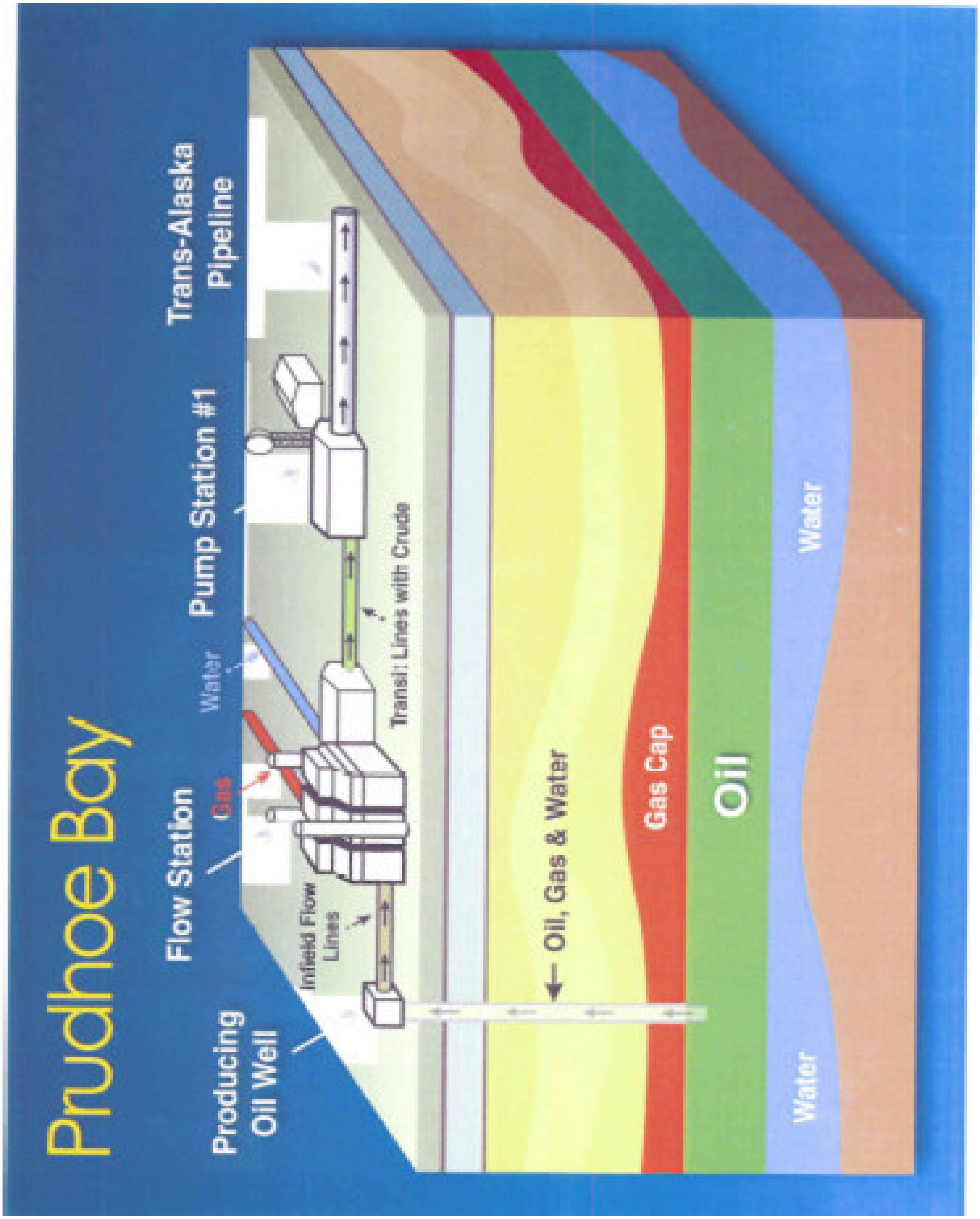

Prudhoe Bay
Producing Oil Well
Flow Station
Gas
Water
Pump Station #1
Trans-Alaska Pipeline
Infield Flow Lines
Transit Lines with Crude
Oil, Gas & Water
Gas Cap
Oil
Water
Water

EXHIBIT 5

Prudhoe Bay Corrosion Spend Versus Production

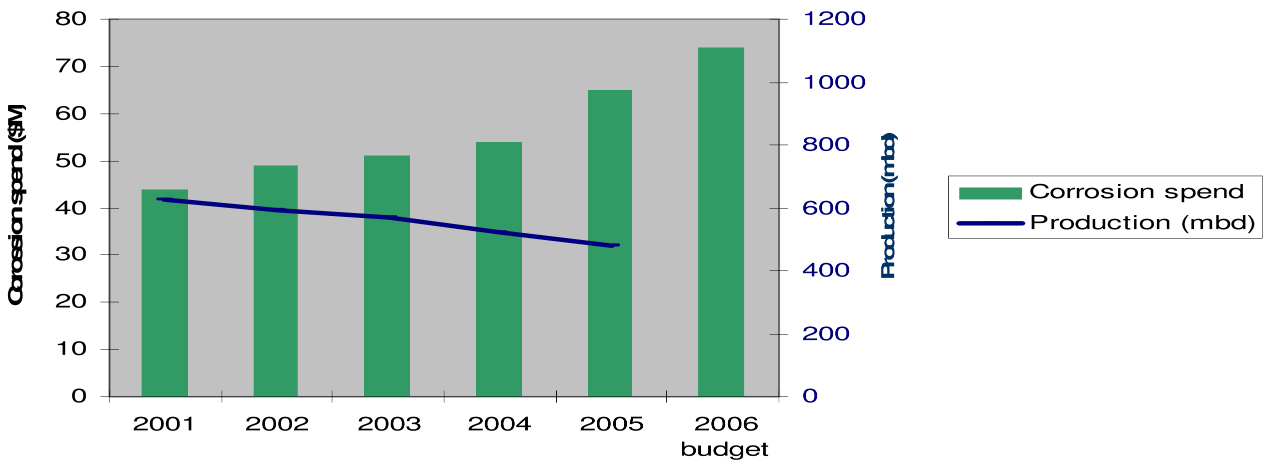


Exhibit 6

Diagram of Inhibitor Injection Rates

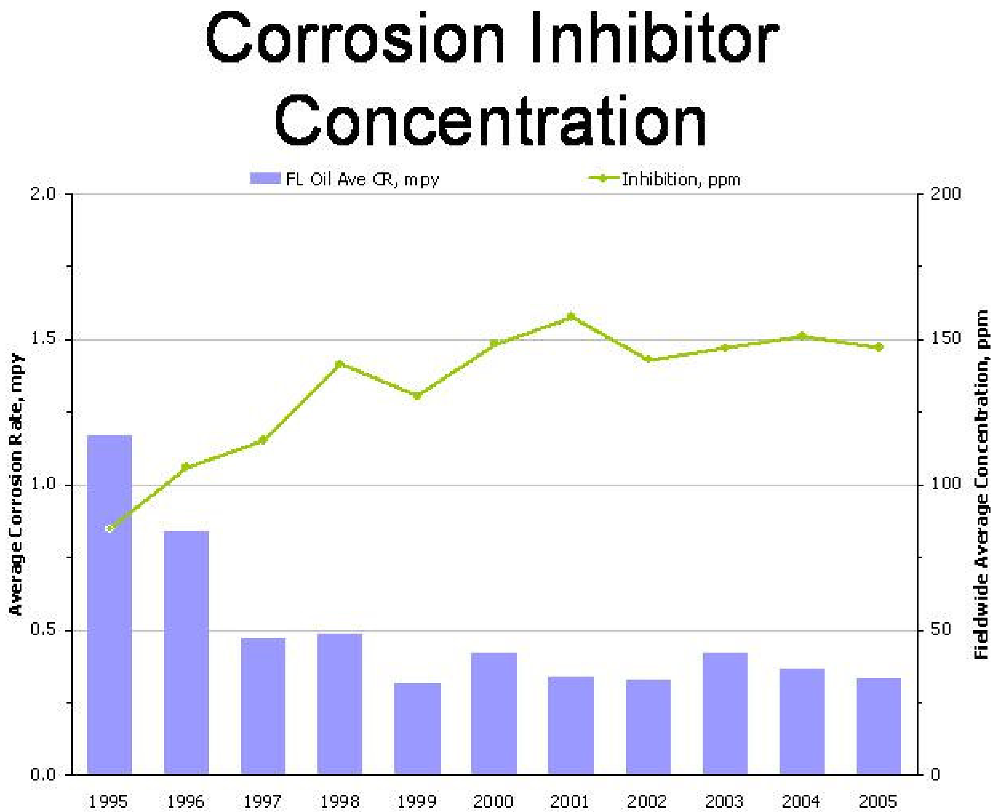
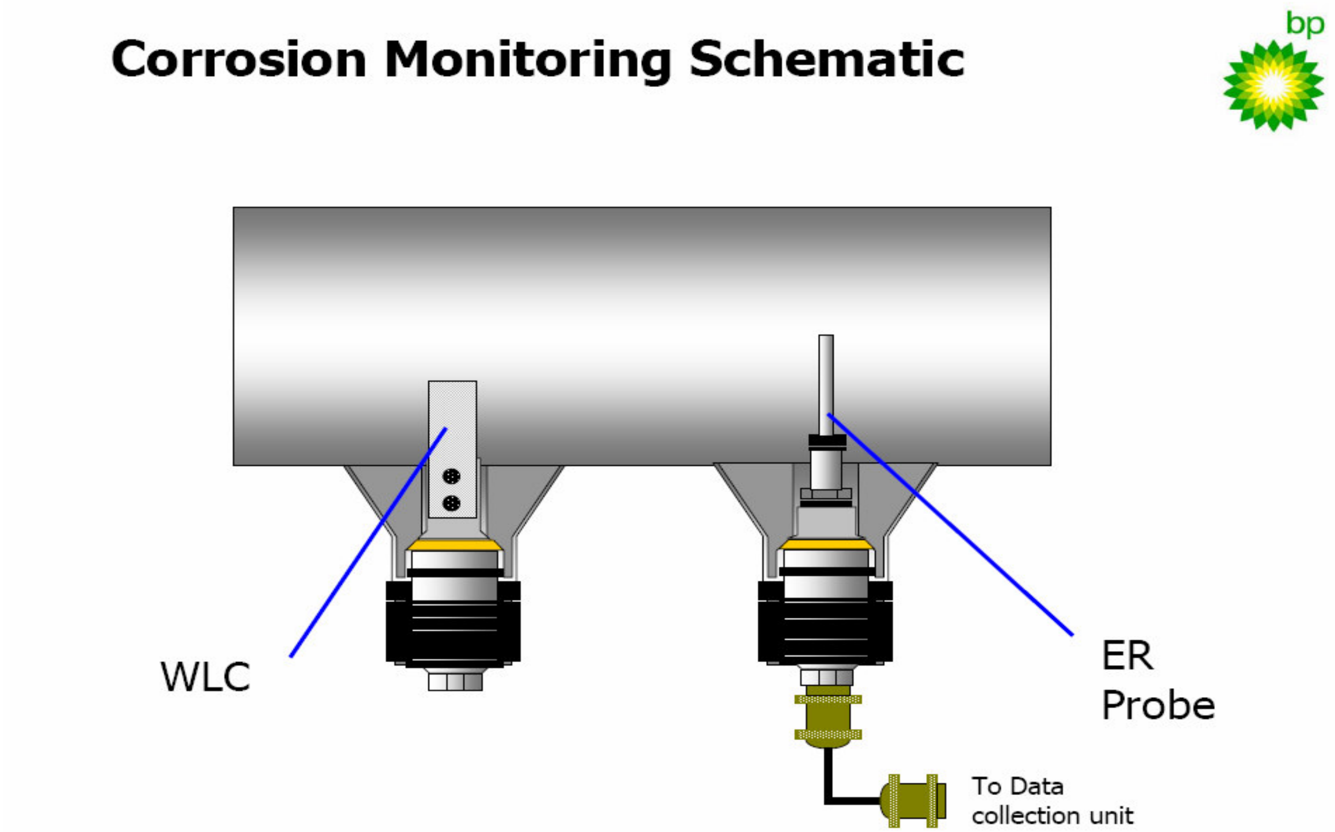


EXHIBIT 7



WLC – Weight loss coupon ER – Electrical resistance

Coupon monitoring is a method that involves exposing a sample of the pipeline material (the coupon) to conditions within the pipe for a given duration, then removing the specimen for analysis. Material loss observed over the exposure period is expressed as corrosion rate.

Exhibit 8

Inhibitor Research Program

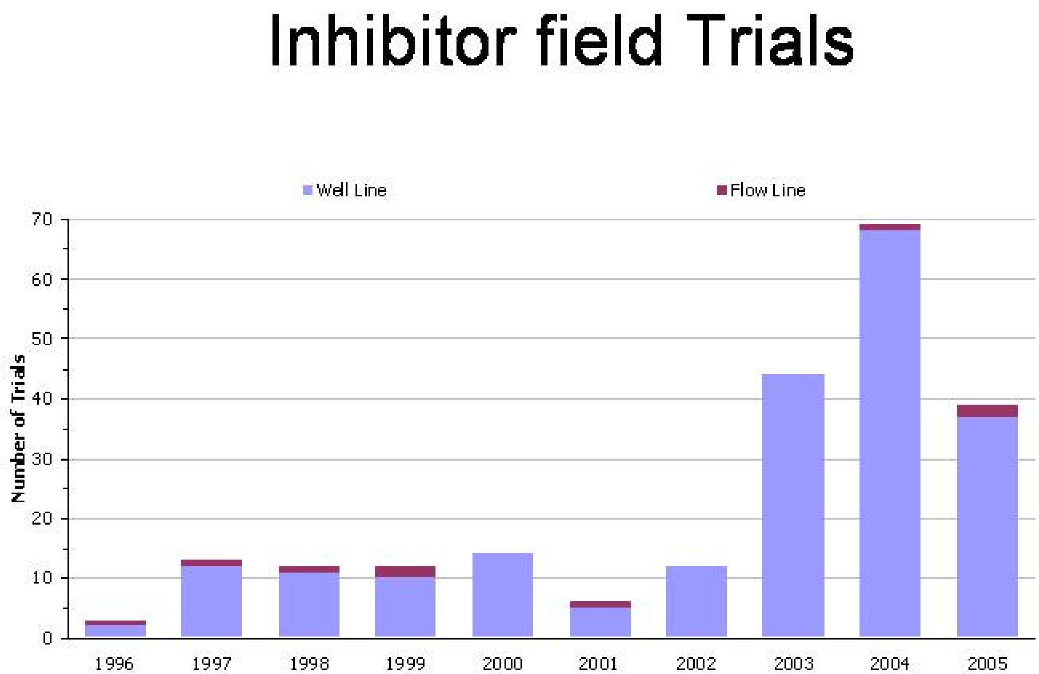
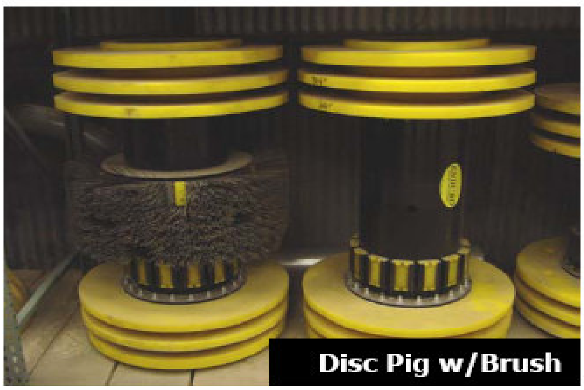


EXHIBIT 9

Pigging Operations



Maintenance pigging is the term for using a mechanical tool to clean the inside of a pipeline. The tool comes in various configurations depending on the application (e.g. foam, disc, cup or brush). Typically the tool is used with fluids remaining in the line. The pressure of the fluids (oil, gas and/or water) acts as the drive mechanism for moving the pig from point to point. Maintenance pigging removes undesirable material, debris (liquid or solid) e.g., wax, paraffin, scale, sediment and water.

For mechanical integrity, specialty tools like "Smart Pigs" rigged with Magnetic Flux Leakage (MFL) and Ultrasonic Thickness testing (UTT) modules are used for accurate inspections of the wall of pipelines. Smart pigs can also perform mapping with inertial guidance technology and detect cracks from stress corrosion. Smart pigs and other automated techniques are helpful in identifying locations that should be more closely monitored using one of the point inspection methods (e.g. visual; ultrasonic; radiographic).

Exhibit 10: Corrosion Coupon Results in OTLs